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"A View from FERC: Electricity Industry Restructuring"

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I. Introduction

Good afternoon. It is indeed a pleasure to be here in New York City and addressing this excellent symposium on utility restructuring.   The transition to competitive electricity markets has been teaching us some valuable lessons. I want to discuss three distinct yet interrelated policy areas – merger policy, RTO policy and the dysfunctional California markets.

II. Merger policy

Let me begin with merger policy.

The electricity utility industry has been undergoing a tremendous reorganization of assets in the last four years or so as utilities position themselves for competition. Shortly after issuing Order 888, the Commission saw that our traditional approach to processing mergers was inadequate and we began to rationalize our policy toward mergers by issuing a new Merger Policy Statement in December of 1996. Less than two months ago, the Commission issued a rule that revises our filing requirements for merger applications and other transactions requiring approval under section 203 of the Federal Power Act. This rule builds upon principles of the 1996 Merger Policy Statement. I would like to take just a few minutes to summarize its major aspects.

The rule sets filing requirements to address three effects of a merger: competition, rates and regulation. The Commission's primary focus is on the competitive effects of proposed mergers. The rule affirms what has come to be known as our Appendix A screening approach to mergers that raise horizontal issues. It adopts guidelines for mergers that raise vertical issues, and adopts filing requirements for analysis and data needed to address those issues. The rule also streamlines filing requirements for mergers that raise no competitive concerns.

I believe that our rule will ensure that the benefits of our merger policy initiative will continue. One of those benefits is the timely processing of applications. By providing the industry with detailed filing requirements, we ensure that more complete applications are filed. Up-front, our staff will have the information they need to process the application quickly. This will lessen the need for asking for more data. Our rule will allow us to continue to act on applications in the short time frames that we set out in the Policy Statement. Indeed, since issuing the 1996 policy statement, the Commission has processed more than 50 mergers in an average time of just 117 days. Fourteen merger filings were made in year 2000, and the Commission acted on all of them by last November. And we've done that in the context of our quasi-judicial procedures and the requirement of transparency and due process for all.

The second benefit of our initiative is reasonable predictability for prospective merger applicants. By stating our standards clearly and in one place, we have empowered all involved with the tools to reasonably predict how the Commission is likely to respond to a particular merger application.

And a third benefit of the rule is ensuring that our merger approval standards are consistent with our over-arching goal of vibrant wholesale competition. While giving merger applicants quick answers to their merger requests, it is critically important that we do not allow mergers to choke off the competition that we and some states are attempting to grow in electricity markets. The analytic standards that we adopted in our rule are sound and based on the standards of the federal antitrust agencies. For horizontal competitive effects, we require applicants to perform a competitive screen analysis. The intent of this screen is to identify mergers that clearly present no competitive concerns. The principal indicator in the screen is the effect of the merger on market concentration. The rule requires that a specific method be used in measuring concentration, but applicants are free to offer alternative analyses that they believe present a more accurate picture of the competitive effects of the merger.

Regarding the vertical competitive effects of a proposed merger, our rule sets out guidelines for defining upstream and downstream markets and describes the types of anticompetitive behavior that the Commission is concerned with regarding vertical mergers, such as foreclosure and raising rivals' costs. The rule also provides guidance on a number of technical issues based on our past case experience.

Our merger filing requirements rule also recognizes the state of flux in the industry and the evolution of analytic tools available for merger evaluation. Let me cite some examples.

- First, computer simulation modeling shows great promise for estimating the market effects of strategic pricing and output decisions by merging firms. We express our openness to their use and will explore modeling at a future technical conference.

- Second, we have experienced multiple mergers in the same region. One pending merger can affect the competitive analysis necessary to evaluate another pending merger. Thus, our final rule requires applicants to take into account, in their competitive analysis, mergers that have been announced but not yet consummated.

- Third, mergers can now have significant competitive effects in retail as well as wholesale markets. While we generally rely on the states to evaluate the effect of a merger on retail markets where they have the authority to do so, our final rule holds open our review of those markets when circumstances warrant.

- And fourth, in the last few years market price data has become much more available due to the advent of trading hubs around the country. This opens competitive analysis to the use of different prices for defining markets. The filing requirements rule requires applicants to perform sensitivity analyses of alternative prices. This will give the Commission the comfort of a robust competitive analysis.

In summary, our filing requirements rule provides the tools to ensure a good competitive analysis of proposed mergers, predictability for applicants, and all of us with the flexibility to keep up with the dramatic changes now taking place in electricity markets.

As I mentioned earlier, the Commission acted on quite a few merger applications in the year 2000. One of the more significant orders addressed the merger between American Electric Power and Central and Southwest. I would like to point out three significant features of this order. First, the Commission for the first time used a vertical analytic framework to address the interaction between electricity transmission and generation facilities. The record developed at hearing showed that this proposed merger would have significant vertical effects by enabling the merged company to foreclose competitors' access to electric transmission and thereby raise prices in electricity markets. The Commission was persuaded to condition the merger on vertical grounds.

Which brings me to the second significant aspect of the AEP order. The Commission conditioned the merger on both AEP and CSW, transferring operational control of their transmission facilities to an RTO. This is the first merger expressly conditioned on RTO membership. The Commission thus explicitly recognized the intersection of merger policy and RTO policy, and the excellent potential market enhancing properties of RTOs. We felt that RTO membership would adequately mitigate the adverse vertical effects of the proposed merger. However, a fully functioning RTO would not be in place within the time frame the parties proposed for closing the transaction. This brings me to the third important aspect of our order.

Our Merger Policy holds that any adverse competitive effects of a merger must be mitigated before the merger is consummated. Thus, the Commission required two forms of interim mitigation to address the vertical effects of the AEP-CSW merger and still allow the merger to go forward until both firms are members of fully functioning RTOs. Those mitigation measures, based on two of the RTO functions set out in Order No. 2000, required AEP East to do two things: (1) contract out its OASIS responsibility to assure independent calculations of Available Transmission Capability and (2) hire an independent entity to monitor the AEP East market area. The applicants accepted and implemented these conditions.

III. RTO policy

The AEP/CSW order brings me to the second broad area of restructuring policy I would like to discuss today, RTO policy. Order No. 2000, now over a year old, issued a clarion call for RTOs to form in all regions of the country. I firmly believe that RTOs that are consistent with FERC's vision in Order No. 2000 are absolutely essential for the smooth functioning of electricity markets. RTOs will eliminate the conflicting incentives vertically integrated firms still have in providing access. RTOs will streamline interconnection standards and help get new generation into the market.

RTOs also improve grid management. Eliminating pancaked transmission pricing will enlarge markets, and a truly regional approach to congestion management can lower costs and increase the amount of capacity available to the market. RTOs will also serve as a regional forum for planning.

By expanding the scope of markets, rationalizing access and interconnection, and facilitating planning and grid expansion, RTOs will help bring about an adequate and efficient supply of generation and transmission facilities. Unfortunately, the Commission chose a voluntary approach to RTO formation, and the results are a hodgepodge.

As we address the proposals that are before us, a number of issues will prove particularly vexing to the Commission.

One of those issues is the scope and configuration of RTOs. To realize their many potential benefits, RTOs must be truly regional in scope - - large and well shaped. Last summer's experience, especially in California, demonstrated that electricity markets are inherently regional in nature. Prices throughout the western United States rose and fell with prices in California. I believe this is a strong argument for a single Western-interconnection-wide RTO. The Commission must insist on RTOs of adequate scope and configuration. Yet, this is the least clearly defined of the requirements in Order No. 2000. How we treat sub-optimally sized RTO proposals will prove crucial to the development of well functioning markets. Markets are regional in scope and require seamless trading. This is not possible if transmission services and standards remain at an inferior sub-regional level.

Unfortunately the Commission's resolve on RTO scope and configuration is not as strong as it should be. Last Wednesday, the Commission decided to accept the proposed scope and configuration of the Alliance RTO. I dissented from that order. I believe it is a significant policy mistake.

Right now, Alliance is shaped more or less like a serpent that stretches from the Great Lakes to the Mid-Atlantic. In earlier orders, the Commission expressed concern that his configuration separates buyers and sellers that constitute predominant west to east trading patterns, and can act as a strategically located toll gate. But the Commission's recent order accepts this configuration on the grounds that Alliance is working on interregional coordination, otherwise know as seams agreements, to smooth the way for market trading.

Essentially, the majority elevated seams management agreements to the status of a complete substitute for the basic characteristic of adequate scope and configuration. This may arise from the voluntary approach, but it is an unfortunate policy call. Realizing the many benefits of RTOs requires the proper scope and configuration. The actual shape of the RTO is important. For example, managing loop flow across a broad region requires a shape that can generally internalize the bulk of the loop flow.

I am very skeptical that mere seams agreements with neighboring control areas will be capable of addressing all inadequacies of a flawed proposed scope and configuration. If seams management agreements were sufficient, there would be no need for any scope and configuration requirements at all. Yet, achieving the reliability and other benefits of RTOs depends on the ability of the RTO to control all of the transmission facilities in an appropriate region. Every seam, even if addressed by an agreement, is a potential bump in the road. The more seams arising from too small or from poorly configured entities, the more dysfunctional the market.

While Order No. 2000 includes a requirement for interregional coordination, this was never intended to be a substitute for adequate scope and configuration. What was intended is that once there is an RTO of appropriate shape and adequate scope and configuration, the RTO must coordinate with other appropriately configured RTOs.

Another potentially vexing RTO issue is innovative rate treatment, or more precisely, when to allow innovative rate treatment, and how generous to be. Order No. 2000 set out a range of innovative rate treatments. Ensuring that transmission owners are not made worse off by committing their assets to an RTO, and incenting the construction of new transmission facilities in an RTO are important goals we are trying to address. The rate treatments intended to meet those goals are available to both the ISO and the transco form of RTOs.

I believe that Order No. 2000 has it right in offering innovative rate treatments to transmission owners that are part of an approved RTO. Trading off higher transmission revenues for the substantial benefits to society of grid regionalization is the policy bargain struck in Order No. 2000. But such proposals must be well justified.

IV. California and the Future of Competitive Markets

Finally, I don't think any discussion of electricity market policy would be complete without discussing the wholesale market in California. One observer said that what has happened in California is the result of a "perfect storm" scenario. I think that is true to a large extent. A number of factors have come together to produce the terrible string of events we have witnessed over the last 6 months: a shortage of capacity, a flawed market design that over relied on the spot market, skyrocketing fuel costs, and increasing demand.

On December 15, 2000, the Commission issued an order that attempts to deal with the problems to the extent of our jurisdiction. I would like to discuss how our order attempts to address the California market.

As I mentioned, one problem has been a market design that incentivized the load serving utilities in California to buy all of their power off of the spot market run by the California PX and to sell any generation the utilities still own on the PX spot market. This stymied most forward contracting by utilities and exposed them to the uncertainties and volatility of the spot market. I don't believe anyone in this room would think that over reliance on the spot market is wise portfolio management. Our order eliminated this buy-sell requirement in order to permit the utilities to move toward a balanced portfolio of forward contracts. Unfortunately, those spot purchases are still occurring and forward contracts have still not been negotiated, although the state legislature is working on this problem. Will there now be an over reliance on very long term contracts.

Another problem in the California market is that the interplay of certain rules has provided an incentive for load to under schedule in the day ahead market, thereby forcing the independent system operator to scramble around at the last minute to find power, usually at extraordinarily high prices. Our order imposes penalties for market participants that fail to schedule at least 95% of their load prior to real time.

As the California crisis continually got worse over the summer, the ISO board found itself occasionally unable to agree on actions and open to charges that it was acting in the interest of certain market segments. Our order requires that the ISO board be replaced with a non-stakeholder board consistent with Order No. 2000's independence criterion. We expect that such a board will be able to act more decisively and be free of allegations of biased decision making.

Clearly, inadequate generation is one of the biggest sources of the high prices in the west. While increasing the supply of generation capacity is almost exclusively in the jurisdiction of the state, our order requires that the ISO and all three jurisdictional California transmission owners file interconnection procedures. This will ensure that the supply of new generation is not slowed down by a lack of clear standards and protracted negotiations regarding interconnecting to the grid.

Finally, in an effort to contain prices, the Commission established a pricing reform and market monitoring program for sales into the PX and ISO real time markets. The current California market design calls for a single market clearing price to be set at the level of the highest bid required to serve the market. Thus, all transactions occur at the highest bid price. This single price feature is suspected of being partly to blame for the wealth transfer that has occurred.

To deal with the high price problem, our December order sets $150/mwh as what is called a "breakpoint." Sellers bidding at or below $150 will receive the market clearing price but not more than $150. Bids above $150 that are needed to serve the market will be paid their actual bids only. Bids above the $150 level will not set the market price. To help ensure against market manipulation, bids above

$150 breakpoint must be reported to the Commission along with certain information, and these prices are subject to refund for 60 days while the Commission staff examines the bidding behavior. This pricing and monitoring reform is intended to be temporary until a permanent comprehensive and systematic market monitoring and mitigation program can be established. We hope to have this in place by May 1.

So what should we think about the future of competitive electricity markets in the wake of the California debacle? First, and most important, of all, the Commission remains committed to completing the transition to competitive wholesale markets. Our December 15th California order is clearly an attempt to fix a broken market so it can perform well going forward.

But in our commitment to competitive markets, we have to guard against unreasonable prices in markets that are dysfunctional. California's market is clearly dysfunctional right now and the wealth transfer has been phenomenal. An electricity business that produces blow out profits at consumer expense is not politically sustainable. I would have preferred that the Commission introduce a temporary "time out" while our reforms and those at the state level are implemented. Albeit reluctantly, I would have imposed a temporary price cap on the California spot markets. Such a price cap could be calculated on a generator-by-generator basis at each generator's variable operating costs plus a reasonable capacity adder perhaps in the range of $25. Importantly, I would exempt new generation sources. Such a price cap would allow generators to recover all costs plus an adequate return, would restore credibility to wholesale market prices and perhaps provide a political path necessary to get this market back on its feet. I do not believe that such a temporary price cap would interfere with price signals that new capacity is needed. Surely suppliers have gotten that message by now. Moreover, I wonder how much faith potential suppliers place in such extraordinarily high and volatile prices. Are these the signals of a stable market? Of course not.
Rest assured that obscene prices can halt the march to competitive markets. Like it or not, electricity markets must produce prices that policymakers find acceptable over time.

I would take two other important lessons from the California market, in addition to those we addressed in our December order. One of those lessons is that there must be some *ex ante* assurance of adequate generating capacity, including a reserve margin. The California market design called for no capacity obligations and very little forward contracting. Presumably, it was expected that the invisible hand of the market would ensure that capacity would show up when needed. Yet given that electricity cannot be stored, relying solely on market signals for capacity could mean significant fluctuations of price and capacity availability as supply and demand adjust. The fundamental role that electricity plays in the social, economic, health and public safety fabric of our society, however, argues that substantial fluctuations in availability and price should be minimized. One way of guarding against these fluctuations would be to place an *ex ante* reserve requirement on the load serving entities that they could meet however they see fit. This is the current practice in PJM, and, given the level of capacity additions planned there, suppliers seem to have confidence in that market design. I would recommend it to all markets.

The other lesson I would take from the California experience is the importance of demand responsiveness to price. Without the ability of end use consumers to respond to price, there is virtually no limit on the price suppliers can fetch in shortage conditions. Consumers see the exorbitant bill only after the fact. This does not make for a well functioning market.

Instilling demand responsiveness into electricity markets requires two things: customers must be able to see prices before they consume, and they must have reasonable means to adjust consumption in response to those prices. Accomplishing both of these on a widespread scale will require technical innovation. But it may not take too much to make a difference. A recent study by EPRI indicates that during this past summer, a 2.5% demand reduction at peak times could have reduced energy costs in California by $700 million. Other studies show that price spikes can be reduced by 73% if just 10% of demand is on real time pricing. I urge that all market participants work diligently to incorporate some degree of demand side responsiveness. It will be particularly critical for the upcoming summer.

And once there is a significant degree of demand response in a market, I believe demand should be allowed to bid so called "negawatts" into organized markets along with the megawatts of the traditional suppliers. This direct bidding would be the most efficient way to include the demand side in the market. But however it is accomplished, the important point here is that market design simply cannot ignore the demand half of the market without suffering the consequences, especially during shortage periods.

V. Conclusion

These are difficult times, but we must all work together to solve these problems.